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Unconventional Natural Gas Resources An Overview Covering the Resources and Environmental Aspects of Production

Hoffman-Holt, Inc.
Silver Spring, MD

Prepared for

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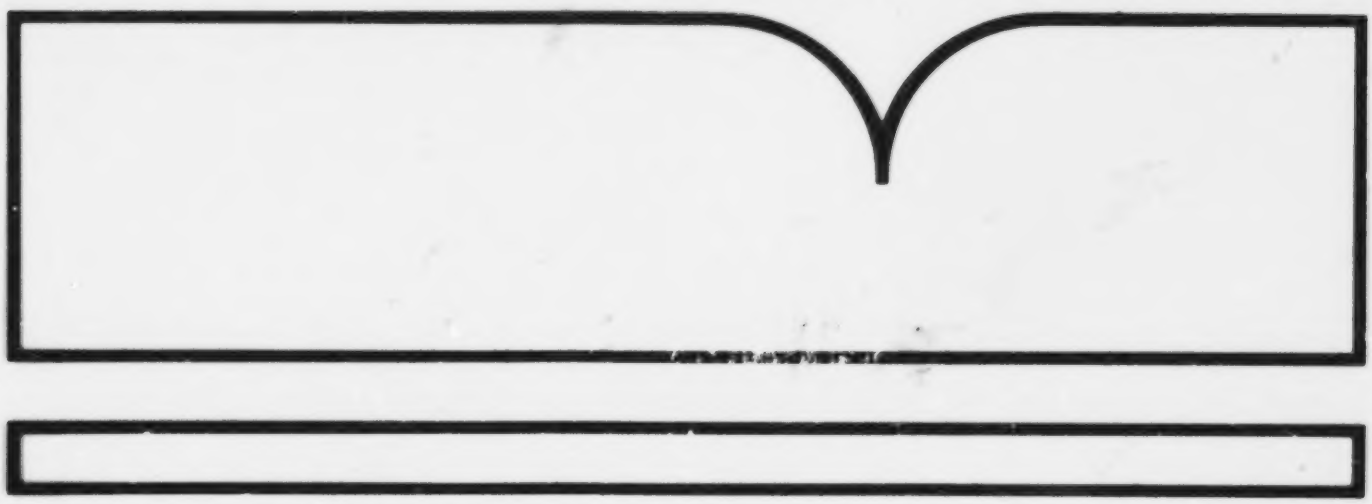

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UNCONVENTIONAL NATURAL GAS RESOURCES:

An Overview Covering the Resources and Environmental Aspects of Production

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Prepared By:

L. Hoffman

Hoffman-Holt, Incorporated

Silver Spring, Maryland

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16. ABSTRACT

This report covers natural gas from the following unconventional sources: western tight sands, Devonian shale, coal deposits, geopressured aquifers, and landfills. This report covers the resource base, potential production levels, and associated environmental aspects.

Over the past 10 years our natural gas reserve level has been declining. At year end 1979 our reserve to production ratio for the entire U.S. was less than 10 years. This has occurred even though exploration for natural gas has been increasing both in terms of number of wells drilled and total footage drilled. There is potential for our natural gas supply to be materially augmented by gas from unconventional resources. In this regard, gas from western tight sands, Devonian shale, and coal seams potentially could provide 1 Tcf of gas in 1985 with significantly greater amounts in 2000. Over the same period, the potential gas from geopressured aquifers and landfills are believed to be considerably less. The environmental concerns vary with source and are minimal for tight sands, Devonian shale, and landfills. Conceivably, significant environmental concerns could be associated with gas recovery from geopressured aquifers.

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a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
- Environment Fossil Fuels - Gas Production Gas Reserves Gas Resources Natural Gas Unconventional Gas	Eastern Gas Shale Geopressured Aquifers Methane from Coal Methane from Landfills Western Gas Sands	

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1.0 INTRODUCTION

As part of our Nation's study of alternative means to achieve energy independence, especially over the critical mid-term period of from 1985 to approximately the year 2000, we are providing an overview of unconventional sources of natural gas, with emphasis on associated environmental aspects.

From an environmental perspective, natural gas is the cleanest fuel at the point of utilization and is currently the major energy source for residential heating, a very dispersed application that environmentally is relatively unregulated. It is therefore of interest to those having the major responsibility for insuring a clean environment to encourage the use of this clean burning fuel as consistent with the implications of such a policy. In order to accomplish this goal we must know the extent of natural gas resources, including the unconventional categories, that may provide significant amounts of natural gas by the year 2000, and any significant environmental consequences that would result from producing gas from unconventional sources.

Natural gas, by definition, is a mixture of the low-molecular weight paraffin-series hydrocarbons consisting mainly of methane, with lesser quantities of ethane, propane and butane and small amounts of higher hydrocarbons. It also frequently contains small proportions of nitrogen, carbon dioxide, hydrogen sulfide and occasionally small proportions of helium. Sour natural gas is gas which contains objectionable amounts of hydrogen sulfide and other sulfur compounds. Natural gas accompanying petroleum always contains appreciable quantities of ethane, propane, butane, as well as some pentane and hexane vapors and is known as wet gas. Dry gas contains less of these higher hydrocarbons. The exact composition of natural gas varies with locality. The heating value of natural gas is usually over 1,000 Btu/cu ft unless nitrogen or carbon dioxide are important components of the gas. Natural gas is used directly as a fuel and as a chemical feedstock. Often when the gas comes from an oil well its higher hydrocarbon content is extracted and used for blending in motor fuel, and for use as a liquefied gas. Gas to be acceptable for injection into a pipeline must meet certain standards. A typical specification is given in the Appendix. The composition of a typical natural gas is shown by Table 1 (1,2).

Table 1
Typical Composition of Natural Gas

Component	Percent Volume[1]
Methane (CH_4)	94.4
Ethane (C_2H_6)	3.8
Propane (C_3H_8)	0.6
Butane (C_4H_{10})	0.3
Pentane (C_5H_{12})	0.2
Nitrogen (N_2)	0.4

Heating value -- 1068 Btu/scf

[1]rounded values

Source: Reference 2

Natural gas reserves encompass gas in natural underground formations that can be economically and legally recovered at the time of determination. Proved natural-gas reserves may be divided into (1) drilled, i.e., producible by existing operating practices and (2) undrilled, i.e., underlying areas which, however, are so related to developed acreage and to the known geology and structure that their productive ability is considered assured. The concept of "reserves" denoting gas deposits of immediate or near-term economic interest differs from "resources", which normally embraces reserves along with marginal, sub-marginal, and latent resources. It should be emphasized that reserves by definition are those volumes of gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in the future, under existing economic and operating conditions. Therefore, the reserve level value will increase as the price level increases due to transfers of portions of the resource base to the reserve base (1,3,4).

Natural gas supplies approximately 27 percent of our total domestic energy value. At the end of 1979, the proved natural gas reserves for the total U.S. (including Alaska) was reported to be 194.9 trillion cubic feet (Tcf). The reserve to production ratio at the end of 1979 was 8.3 years for the lower-48 states and 9.8

years for the total U.S. (Table 2). The bulk of these proved reserves are found in conventional reservoirs (high-permeability sandstone and carbonate reservoirs) which are generally located in the Gulf Coast and Southwest regions of the United States. These reserves have been developed because they can be easily produced, have high recovery efficiencies, and provide acceptable profit incentives to the gas-producing companies (5,6).

Table 2
Year-End 1979 Natural Gas Reserves

	Lower-48 States	Total U.S.
Proved Reserves	163.0 Tcf	194.9 Tcf
Reserve Additions in 1979	13.7 Tcf	14.3 Tcf
Production in 1979	19.7 Tcf	19.9 Tcf
Reserve to Production Ratio	8.3 years	9.8 years

Source: Reference 6 (with rounding). This was the last year of industry published data.

Even though the natural gas reserve level (by virtue of definition) is well defined, there is considerable uncertainty as to the remaining recoverable natural gas resources. The American Gas Association (Reference 7) lists 14 estimates by reputable parties (e.g. oil companies, USGS, National Academy of Sciences, etc.) of the recoverable natural gas resources as of end-year 1979. The values indicated (Reference 7) range from 257 to 1,220 Quads. Obviously the uncertainty as to the remaining recoverable resource are substantial.

In addition to the conventional natural-gas resources there are a number of so-called unconventional gas resources that hopefully will have the potential to meaningfully augment our natural gas supply. This report addresses unconventional gas sources as to their potential for providing meaningful levels of industrial and pipeline quality gas. The following sources are addressed:

- The gas-bearing Devonian shales of the eastern United States (eastern gas shales),
- The low-permeability (tight) gas sandstones of the Rocky Mountain region (western gas sands),

- The free methane (natural gas) present within coal seams (methane from coal),

- The high-pressure, methane-saturated saltwater aquifers of the Gulf Coast region (geopressured aquifers), and

- Landfills resulting from the disposal of waste from residential, commercial, and industrial sources.

Gas from landfills is not generally classified in the unconventional category. However since this gas is currently being commercially extracted it is included.

This report will include the following:

- An estimate of the resource base, current and projected unconventional gas production (in Quads) and general market applicability as compared to conventional natural gas;

- An analysis of typical unconventional gas constituents (with percentage values); and

- Discussion of the environmental aspects of producing gas from unconventional sources.

- An indication of required gas cleanup relative to conventional natural gas practices (to permit marketing).

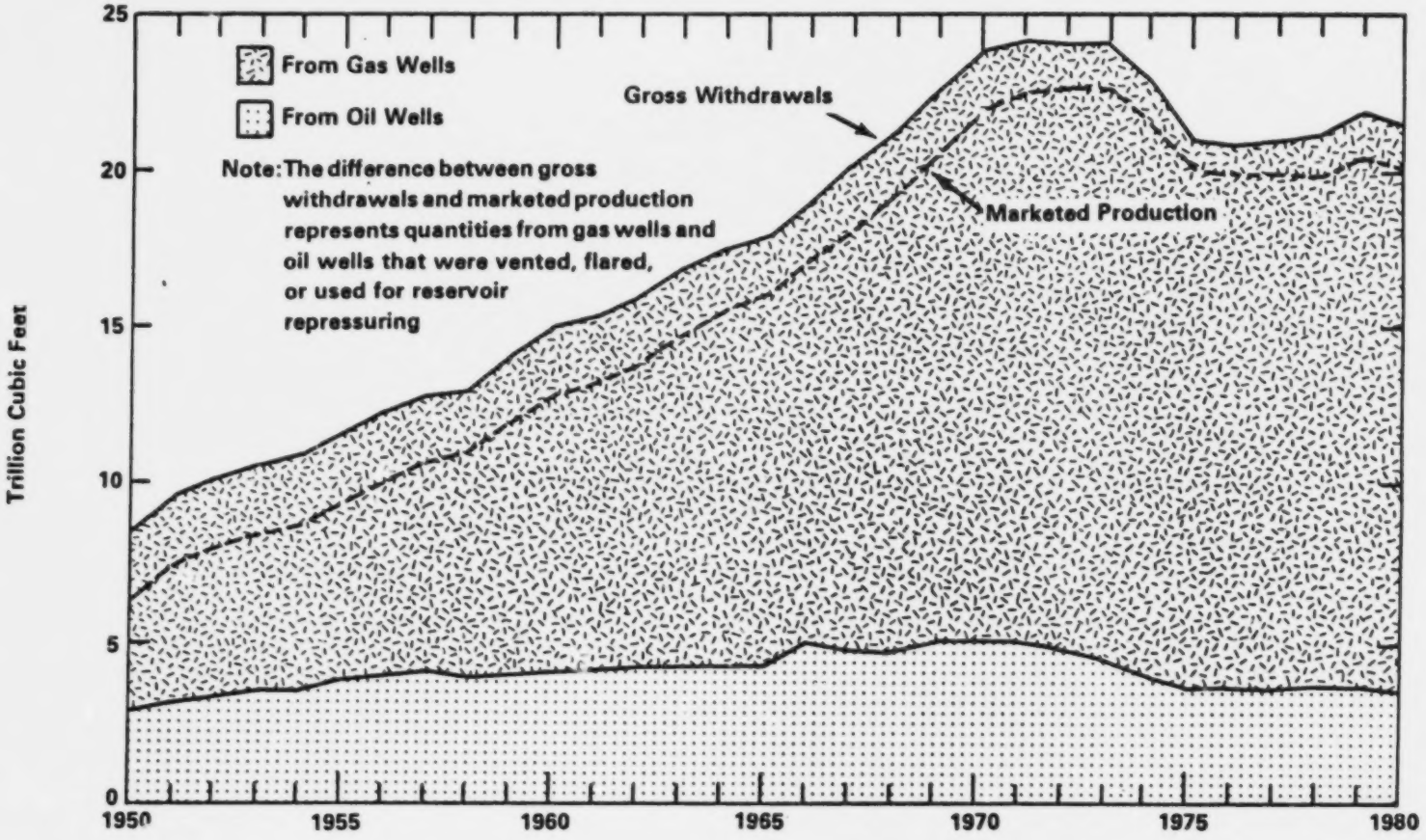
2.0 NATURAL GAS UTILIZATION

As previously stated, natural gas currently supplies approximately 27 percent of the energy consumed in the United States. Natural gas gross withdrawals and marketed production for the period 1950 through 1980 are given in Figure 1. The consumption of natural gas by end-use sector for the same period is given in Figure 2. A natural gas flow diagram for 1980 is given by Figure 3.

Since 1970, the proved U.S. natural gas reserves have been declining with productions greater than additions (Figure 4). Currently the proved reserve to annual consumption ratio is less than 10. The Energy Information Administration (Reference 5) indicates that over the past 10-15 years the return-to-drilling value (reserve additions per foot drilled) has rapidly declined with the implication that unconventional gas resources will need to be used to help support our natural gas requirement.

The trends in exploratory well drillings, total wells (i.e. exploratory and developmental), average well depth, and footage drilled are provided by Tables 3 and 4. As indicated by Table 4, the footage drilled for gas wells (excluding dry holes) was less than 30 million feet per year for the period of 1950 through 1972. A very significant upward trend in drilled footage started in 1973 with continuous yearly increases each year thereafter (i.e. to latest year of record) with an estimated drilled footage, 1980 value, in excess of 85 million feet.

In general, there is a five to 15-year lag between drilling and the subsequent addition to the reserve base. This is due, in part, to the definition of reserve base and to the related verification and quantification process. The recent significant increase in drilled footage and the time lag between drilling and additions to the reserve base may imply an understated reserve base.



Source: Reference 5

Figure 1

Natural Gas Gross Withdrawals and Marketed Production

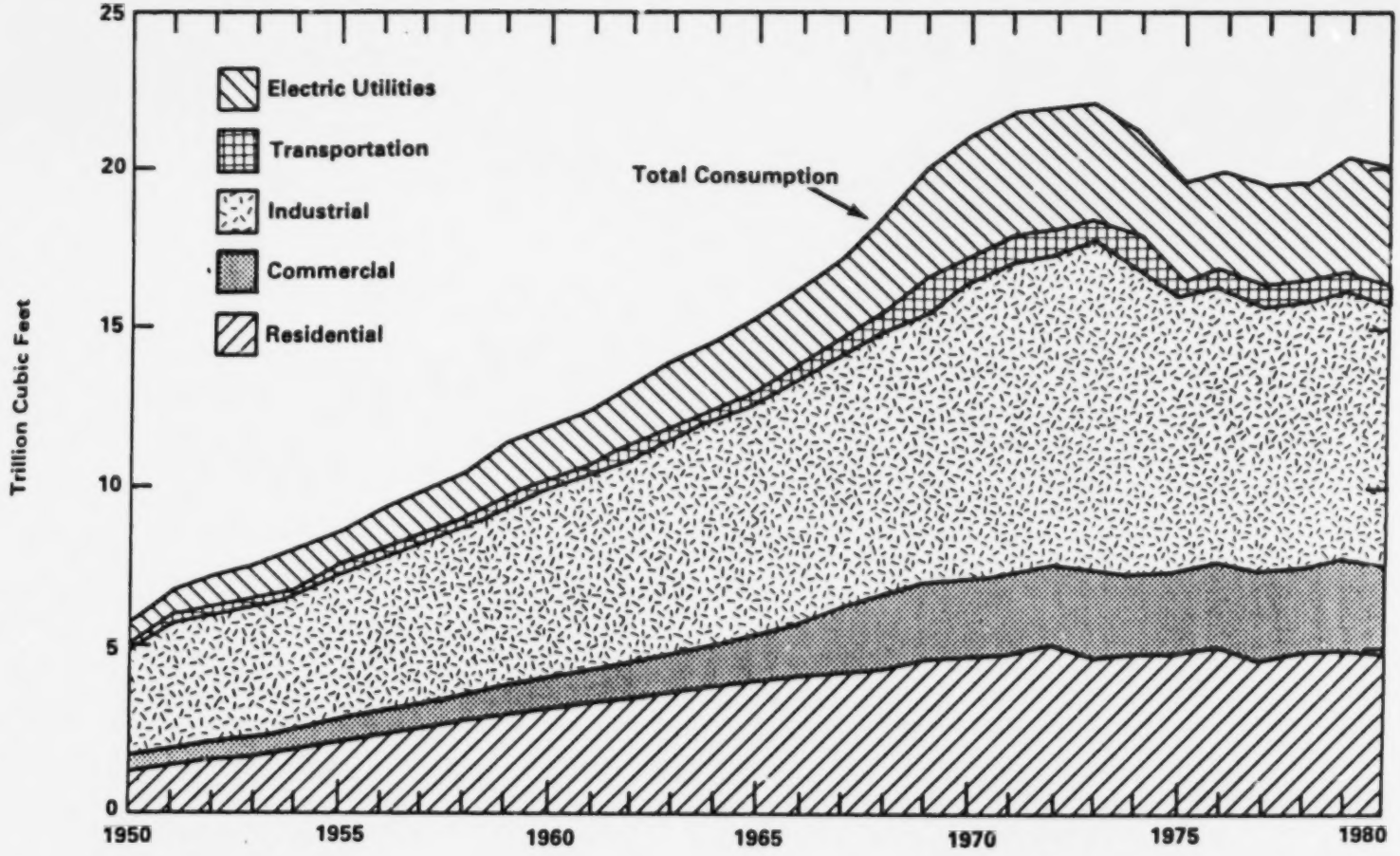


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Figure 2

Consumption of Natural Gas by End-Use Sector

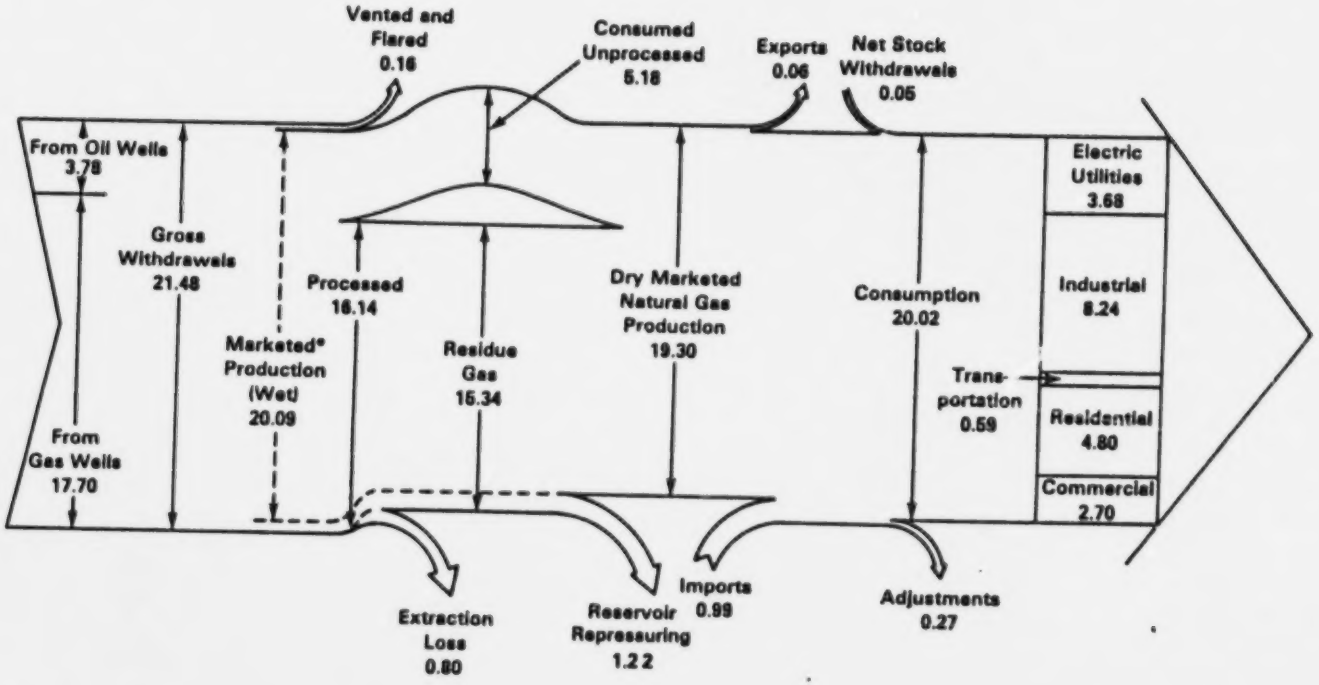

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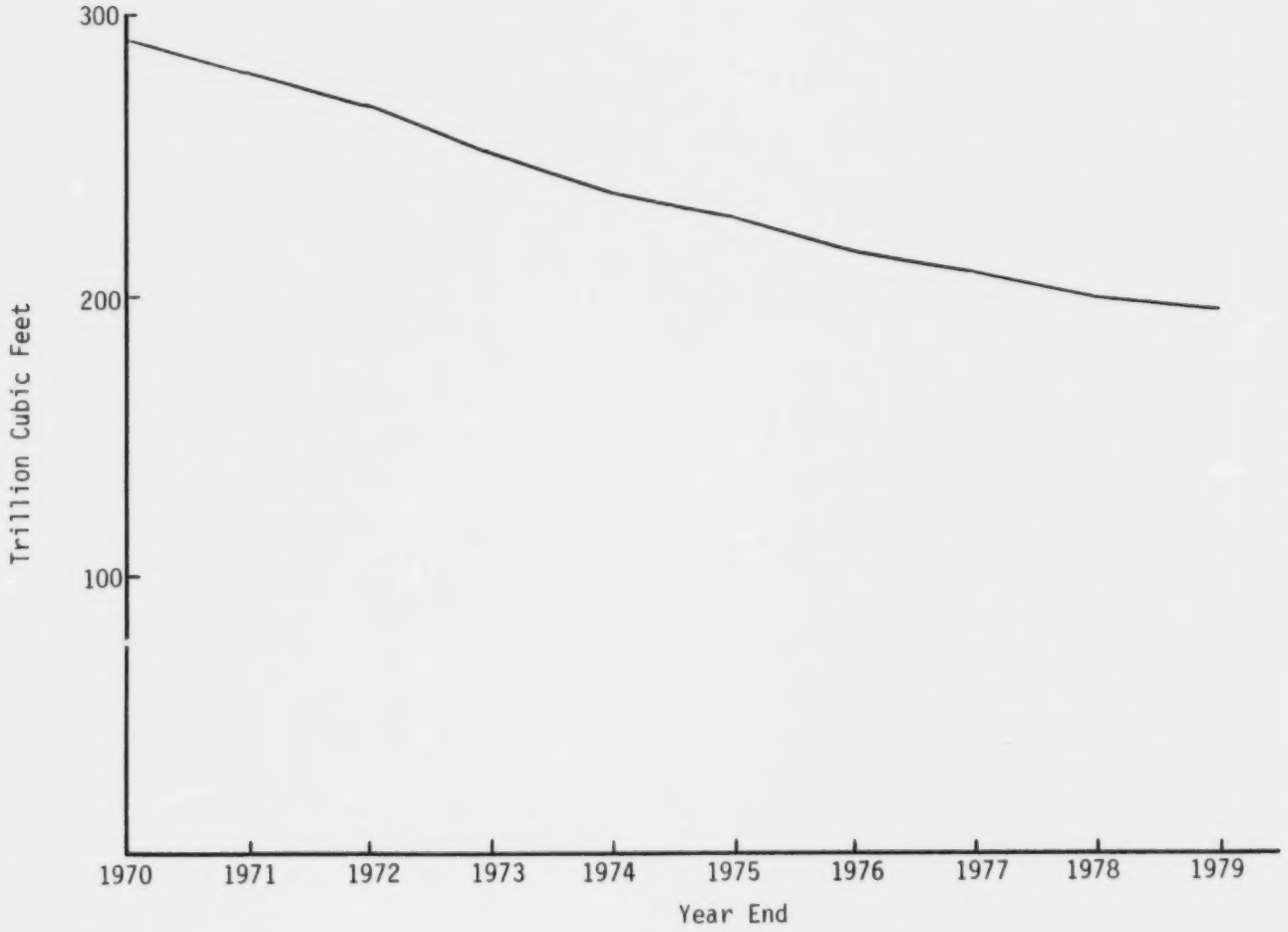
Figure 3

Natural-Gas Flow Diagram, 1980
(Trillion Cubic Feet)



Source: Reference 5

Figure 4
U. S. Natural Gas Reserves

Table 3

Exploratory Wells Drilled for Oil and Gas, 1950-1980

Year	Wells Drilled (thousands)				Footage Drilled (million feet)				Average Depth (feet)				Successful Wells (percent)
	Oil	Gas	Dry Holes	Total	Oil	Gas	Dry Holes	Total	Oil	Gas	Dry Holes	Total	
1950	1.58	0.43	8.29	10.31	6.9	2.4	31.0	40.2	4,335	5,466	3,733	3,898	19.5
1951	1.76	0.45	9.54	11.76	8.1	2.5	38.7	49.3	4,609	5,497	4,059	4,197	18.9
1952	1.78	0.56	10.09	12.42	8.5	3.4	43.7	55.6	4,781	6,071	4,334	4,476	18.8
1953	1.98	0.70	10.63	13.31	9.4	4.0	47.3	60.7	4,761	5,654	4,447	4,557	20.1
1954	1.98	0.73	10.39	13.10	9.4	4.4	45.8	59.6	4,740	6,059	4,408	4,550	20.7
1955	2.24	0.87	11.83	14.94	10.8	5.2	53.2	69.2	4,819	5,964	4,498	4,632	20.8
1956	2.27	0.82	13.12	16.21	11.1	5.2	58.0	74.3	4,901	6,301	4,425	4,587	19.1
1957	1.94	0.86	11.90	14.71	9.8	6.0	53.4	69.2	5,036	6,898	4,488	4,702	19.1
1958	1.74	0.82	10.63	13.20	8.7	5.5	47.3	61.5	4,993	6,657	4,449	4,658	19.4
1959	1.70	0.91	10.58	13.19	8.5	6.0	48.7	63.3	5,021	6,613	4,602	4,795	19 8
1960	1.32	0.87	9.52	11.70	6.8	5.5	43.5	55.8	5,170	6,298	4,575	4,770	18.7
1961	1.16	0.81	9.02	10.99	5.9	5.2	43.3	54.4	5,099	6,457	4,799	4,953	17.9
1962	1.21	0.77	8.82	10.80	6.2	5.2	42.2	53.6	5,124	6,728	4,790	4,966	18.4
1963	1.31	0.66	8.69	10.66	6.4	4.2	42.8	53.5	4,878	6,370	4,933	5,016	18.5
1964	1.22	0.56	8.95	10.73	6.7	4.2	44.6	55.5	5,509	7,547	4,980	5,174	16.6
1965	0.95	0.52	8.00	9.47	5.4	3.8	40.1	49.2	5,672	7,295	5,007	5,198	15.4
1966	1.20	0.70	8.42	10.31	6.8	5.8	43.1	55.7	5,700	8,321	5,117	5,402	18.4
1967	0.99	0.53	7.36	8.88	5.7	4.0	38.2	47.8	5,758	7,478	5,188	5,388	17.1
1968	0.95	0.49	7.44	8.88	5.6	3.7	41.6	51.0	5,914	7,697	5,589	5,739	16.2
1969	1.08	0.62	8.00	9.70	6.6	5.0	45.9	57.5	6,054	8,092	5,739	5,924	17.5
1970	0.79	0.48	6.42	7.69	5.1	3.7	36.5	45.3	6,399	7,639	5,687	5,882	16.5
1971	0.65	0.44	5.83	6.92	3.7	3.3	33.3	40.4	5,702	7,616	5,716	5,835	15.7
1972	0.68	0.60	6.25	7.54	4.0	4.6	36.4	45.0	5,850	7,641	5,828	5,975	17.0
1973	0.62	0.90	5.95	7.47	3.9	6.2	34.8	44.8	6,226	6,856	5,844	5,997	20.3
1974	0.81	1.20	6.61	8.62	4.9	7.7	37.7	50.3	5,961	6,421	5,709	5,832	23.3
1975	0.97	1.17	7.07	9.21	5.7	8.0	40.1	53.8	5,863	6,831	5,678	5,844	23.3
1976	1.05	1.40	6.78	9.23	6.1	9.2	37.5	52.8	5,864	6,550	5,525	5,719	26.5
1977	1.21	1.48	7.28	9.96	7.1	9.7	40.9	57.7	5,834	6,550	5,626	5,788	27.0
1978	1.12	1.60	7.95	10.68	6.8	10.8	45.6	63.2	6,039	6,747	5,740	5,923	25.6
1979	1.24	1.78	7.46	10.48	7.5	11.8	43.2	62.5	6,023	6,599	5,794	5,958	28.8
1980[1]	1.61	1.99	8.36	11.96	9.4	14.0	47.0	70.3	5,819	7,022	5,622	5,882	30.1

[1] Preliminary.

Note: Sum of components may not equal total due to independent rounding. Average depths are calculated using unrounded data.

Sources: • 1950 through 1960 — American Association of Petroleum Geologists, *Statistics on Exploratory Drilling in the United States, 1940 through 1960*, Tulsa, Oklahoma, 1962, pp. 4-19. • 1961 through 1965 — *Bulletin of the American Association of Petroleum Geologists*, "North American Developments" issue, Tulsa, Oklahoma. • 1966 through 1980 — American Petroleum Institute, *Quarterly Review of Drilling Statistics for the United States*, annual summaries and monthly reports.

Source: Reference 5

Table 4

Total Wells[1] Drilled for Oil and Gas, 1950-1980

Year	Wells Drilled (thousands)				Footage Drilled (million feet)				Average Depth (feet)				Successful Wells (percent)
	Oil	Gas	Dry Holes	Total	Oil	Gas	Dry Holes	Total	Oil	Gas	Dry Holes	Total	
1950	23.81	3.44	14.80	42.05	92.7	13.7	51.0	157.4	3,893	3,979	3,445	3,742	64.8
1951	23.18	3.44	17.03	43.64	95.1	13.9	63.1	172.1	4,103	4,056	3,706	3,944	61.0
1952	23.29	3.51	17.76	44.56	98.1	15.3	70.7	184.1	4,214	4,342	3,983	4,132	60.1
1953	25.32	3.97	18.45	47.74	102.1	18.2	73.9	194.2	4,033	4,599	4,004	4,069	61.4
1954	28.14	4.04	18.93	51.11	113.4	18.9	75.8	208.0	4,028	4,670	4,004	4,070	63.0
1955	30.43	4.27	20.45	55.15	121.1	19.9	85.1	226.2	3,981	4,672	4,161	4,101	62.9
1956	30.53	4.53	22.11	57.17	120.4	22.7	90.2	233.3	3,942	5,018	4,079	4,080	61.3
1957	27.36	4.48	20.16	52.00	110.0	23.8	83.2	217.0	4,021	5,326	4,126	4,174	61.2
1958	23.77	5.00	18.16	46.94	93.1	25.6	74.6	193.3	3,916	5,106	4,110	4,118	61.3
1959	24.04	4.93	18.59	47.56	94.6	26.6	79.5	200.7	3,935	5,396	4,275	4,220	60.9
1960	22.26	5.15	18.21	45.62	86.6	28.2	77.4	192.2	3,889	5,486	4,248	4,213	60.1
1961	21.44	5.49	17.33	44.25	85.6	29.3	74.7	189.6	3,994	5,339	4,311	4,285	60.8
1962	21.73	5.35	17.08	44.16	88.4	28.9	77.3	194.6	4,070	5,408	4,524	4,408	61.3
1963	20.14	4.57	16.76	41.47	81.8	24.5	76.3	182.6	4,063	5,368	4,552	4,405	59.6
1964	19.90	4.69	17.69	42.29	80.5	25.6	81.4	187.4	4,042	5,453	4,598	4,431	58.2
1965	18.06	4.48	16.23	38.77	73.3	24.9	76.6	174.9	4,059	5,562	4,723	4,510	58.2
1966	16.78	4.38	15.23	36.38	67.3	25.9	69.6	162.9	4,013	5,928	4,573	4,478	58.1
1967	15.33	3.66	13.25	32.23	58.6	21.6	61.1	141.4	3,825	5,898	4,616	4,385	58.9
1968	14.33	3.46	12.81	30.60	59.5	20.7	64.7	145.0	4,153	5,994	5,053	4,738	58.1
1969	14.37	4.08	13.74	32.19	61.6	24.2	71.4	157.1	4,286	5,918	5,195	4,881	57.3
1970	13.02	3.84	11.26	28.12	57.1	22.9	59.3	139.3	4,385	5,961	5,265	4,953	60.0
1971	11.86	3.83	10.16	25.85	48.6	22.6	53.1	124.2	4,094	5,907	5,221	4,806	60.7
1972	11.31	4.93	11.06	27.29	48.5	26.8	59.3	134.6	4,293	5,431	5,363	4,932	59.5
1973	9.90	6.38	10.30	26.59	44.6	35.6	56.1	136.4	4,508	5,576	5,449	5,129	61.2
1974	12.78	7.24	11.67	31.70	50.2	39.0	61.4	150.6	3,927	5,385	5,256	4,750	63.2
1975	16.41	7.58	13.25	37.24	64.5	41.9	68.0	174.4	3,932	5,531	5,133	4,685	64.4
1976	17.06	9.08	13.62	39.76	66.7	47.5	67.6	181.8	3,910	5,229	4,961	4,571	65.7
1977	18.91	11.38	14.69	44.98	75.3	59.5	76.0	210.8	3,982	5,233	5,173	4,687	67.3
1978	17.78	13.06	16.22	47.06	72.5	70.2	84.4	227.1	4,081	5,373	5,203	4,826	65.5
1979	19.38	14.68	15.75	49.82	78.6	77.8	82.3	238.7	4,057	5,296	5,223	4,791	68.4
1980[a]	26.98	15.74	18.09	60.81	109.5	85.1	89.7	284.3	4,057	5,407	4,959	4,675	70.3

[1] Includes exploratory and development wells; excludes service wells, stratigraphic tests, and core tests.
[a] Preliminary.
Note: Sum of components may not equal total due to independent rounding. Average depth may not equal average of components due to independent rounding.
Sources: •1950 through 1965 — *World Oil*, "Forecast-Review" issue, Houston, Texas. • 1966 through 1980 — American Petroleum Institute, *Quarterly Review of Drilling Statistics for the United States*, annual summaries and monthly reports.

Source: Reference 5

3.0 UNCONVENTIONAL GAS SOURCES

3.1 General

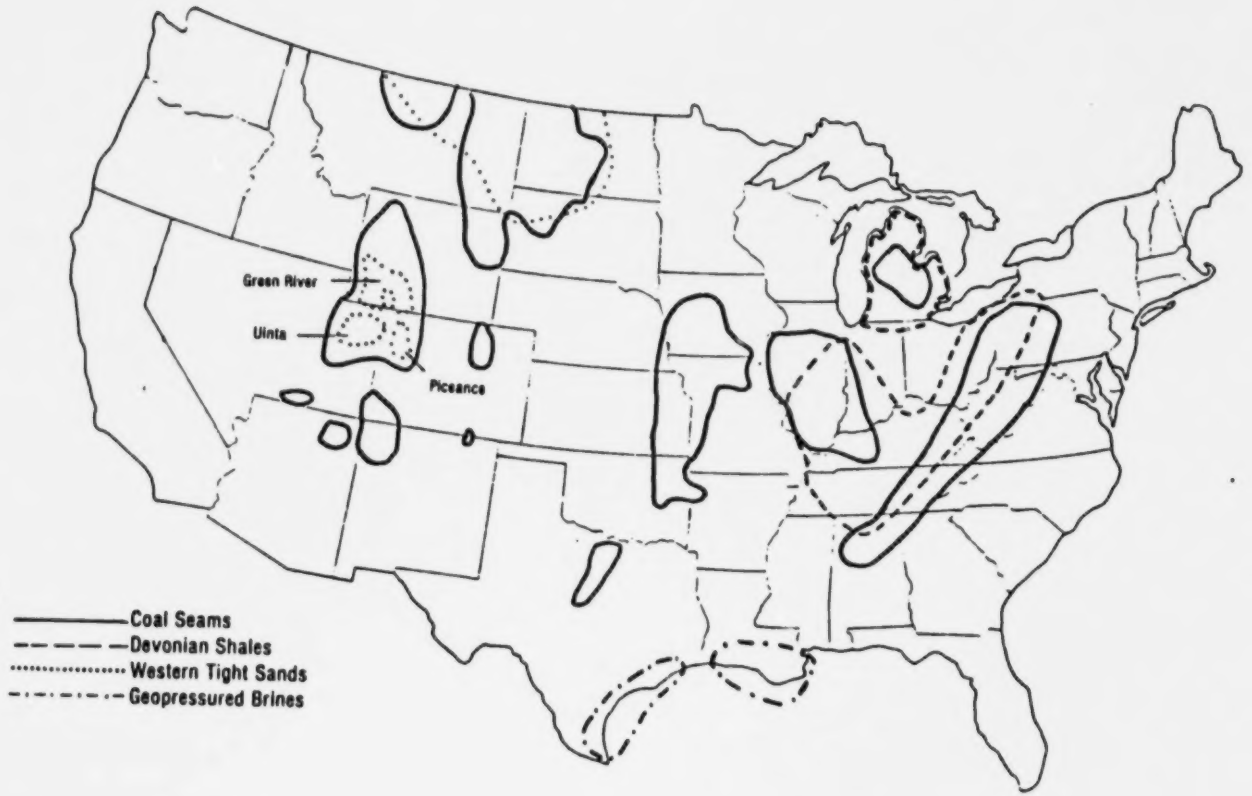
The potential contribution of unconventional gas to our eventual supply is a great unknown. Unconventional sources have not been well exploited. They include gas-bearing geologic formations that are hard to reach and/or are low-permeability formations that must await the determination of technical and economic feasibility. Large uncertainties include: (1) the magnitude of the gas resource contained in these sources, (2) the ability to extract the gas, and (3) the economics of extraction. There have been widely varying estimates of the resource base, the reserves, and the potential gas supply in the foreseeable future (i.e. to year 2000). The low and high-estimate magnitude, clearly indicating that knowledge about the geology of unconventionals and whether they are producible, is very tenuous.

Figure 5 indicates the location of considered unconventional gas-bearing geologic formations. Tables 5 and 6 obtained from The scientists' Institute for Public Information (Reference 8) indicate the uncertainty in both the resource base and the potential gas supply from these sources. It should be noted, as listed in Table 6, that TRW's most probably gas supply estimate for the year 2000 is 10 Tcf, which represents a value that is over 50 percent of the current conventional gas production level.

Relatively small amounts of gas have been and are currently being produced from unconventional resources. Table 7, based on referenced sources, indicates recent annual production levels. Sections 3.2 through 3.6 that follow provide a discussion on each of the considered natural gas resources.

3.2 Devonian Shales (Eastern Gas Shale) (11)

Eastern Gas Shales are shale formations of Mississippian and middle and late Devonian age. These formations underlie much of the Applachian, Michigan and Illinois Basins. Shale deposits in the Appalachian Basin, and to a lesser degree those of the Michigan and Illinois Basins, have been known to produce gas since the nineteenth century. The attractiveness of this resource is enhanced by its proximity to natural gas markets in the populous East and industrial Mid-west.



Source: Reference 8

Figure 5

Location of Unconventional Natural Gas Resources

TABLE 5

Resource Base of Unconventional

Sources of Natural Gas[1]

	Base (Tcf)	
Source	In-place	Recoverable
Western tight sands	50-600	25-310 (170)[2]
Devonian shale	75-700	10-500 (30-285)
Coal seam methane	70-860	15-490 (300)
Geopressured methane	3,000-50,000	150-2,000 (150)
Total	3,200-52,000	200-3,000 [650-905]

1 TRW Energy Systems Group. "Analysis of Benefits for R&D Pro- for Unconventional Gas Resources Proposed by the Gas Research Institute". March, 1978. Numbers are rounded to the nearest whole number divisible by ten. Note: Bracketed numbers have been added by the author.

2 Over 100 estimates of the resource base for unconventional sources have been published. The TRW estimates for each of the four unconventional coincide with the ranges of estimates published elsewhere. The most frequent stated estimates of recoverable reserves are shown in parentheses. The figures assume recoverability at marginal costs up to $4.00 per mcf. The TRW figures were chosen not only because they represent the widest range, but also because they have been used extensively by others in the literature as a basis for their independent analyses. The trend of resource recoverability with increasing price is a great unknown. Undoubtedly recoverable amounts would increase as based on higher marginal costs. However, technical limitations are estimated to be such that cost is not always the limiting factor.

Landfill gas is not indicated above due to the fact that it is not a resource base in the conventional sense with the level dependent on a resource creation over a period of time. In addition, in comparison with the above listed unconventional resources, the potential of landfill gas is very small.

Source: Reference 8

TABLE 6

Potential Gas Supply From Unconventional Sources--1985 and 2000[1]

Source	------Supply (Tcf)------ 1985	2000
Western tight sands	0.35-0.78 (0.52)	3.0-6.9 (4.6)
Devonian shale	0.12-0.26 (0.17)	1.0-2.3 (1.5)
Coal seam methane	0.3-0.8 (0.5)	2.5-5.6 (3.7)
Geopressured methane	0	0.22-0.5 (0.33)
Total[2,3,4]	0.75-2.0 (1.0)	7.0-15.0 (10)

[1] TRW Energy Systems Group. "Analysis of Benefits for R&D Projects for Unconventional Gas Resources Proposed by the Gas Research Institute". March, 1978. The figures shown represent the range of numerous estimates of production anticipated from unconventional sources. Expected production estimated by TRW is given in parentheses (8).

[2] The American Gas Association estimates 0.9 tcf and 5.0 tcf respectively in 1985 and 2000 (8).

[3] Totals are not the sum of figures above; they are rounded to the nearest whole number. [sic]

[4] Ranges can be attributed to assumptions regarding technology and price. A Gas Research Institute analysis has found that doubling the wellhead price from $3 to $6 per thousand cubic feet using existing technology increased total production by 75 percent; whereas, at each of the price levels, advanced technology has the potential to double gas production (6).

Source: Reference 8

TABLE 7

Recent Production From Unconventional Resources

Resource	Recent Production Level (Tcf/yr)	Comment
Western Tight Sands[1]	0.10	In 1980
Devonian Shale[2]	0.15	In 1979 from 9600 wells
Coal Seam Methane	(none identified)	
Geopressurized Aquifers	(none identified)	
Recovered Landfill Gas[3]	Less than 0.004	In 1980

---

[1] Base on data contained in Reference 9 and FERC definition of tight sands

[2] Reference 8

[3] Based on Reference 10

To a great extent, recent attention has been focused on the western portion of the Appalachian Basin. Of the approximately 160,000 square miles underlying the western Appalachian Basin, about 40 percent is underlain by Devonian black and brown shale deposits at depths of less than 4,000 feet, 50 percent at depths between 4,000 and 8,000 feet and the remainder at depths below 8,000 feet. The depth at which the resource occurs is important because at depths of less than 1,500 feet much of the gas may have escaped to the surface, and at depths greater than 8,000 feet thermal maturation processes may have driven the gas from the shale.

Studies indicate that gas is produced from natural fracture systems within the Devonian Shales. The fractures serve as reservoirs and also as channels of high permeability for movement of the gas to the wellbore. Because the gas-production rates associated with conventionally emplaced wells have generally been too low to be economically attractive, efforts have been directed toward developing fracture stimulation and drilling techniques to connect more gas-containing natural and induced fractures to the wellbore. However, development of this resource by the private sector has been slow because little was known about the shale's fracture systems and about how reservoir stimulation-technology should be applied. The high variability in the geologic setting of the shales adds to the uncertainties facing potential developers. The result is that, in the past, gas production has been unpredictable and the economics marginal. Undoubtedly, economic attractiveness will improve with increasing natural gas prices.

Estimates of the size of the resource and the economics of recovery vary considerably. Certain basic data on this resource are available from approximately 9,600 producing wells in the Appalachian region today, but a lack of geologic information on most of the Appalachian Basin makes accurate resource and reserve estimates difficult. The gas produced from this resource to date has been limited to an estimated 2.5 trillion cubic ft. (Tcf).

3.3 Western Tight Gas (8,11)

Geologic studies by both industry and government have indicated that a large resource of natural gas exists in the western states (see Figure 5). Most of this potential resource lies within low-permeability (tight) reservoirs. Specifically, the formations have low porosity (the mineral particles making up the formations are so tightly packed together that there is little space among them) and the formations have low permeability (gases and fluids do not move readily among the particles). Specifically, interest in tight sand gas deposits centers on 13 western and southwestern gas basins and a large shallow gas area of the Northern Great Plains

Province. The contained gas-bearing sands are often interspersed with shales that are thousands of feet in gross thickness. Potentially productive reservoirs within such areas might number a hundred or more. These sand reservoirs may range in thickness from a few feet to 100 feet or more.

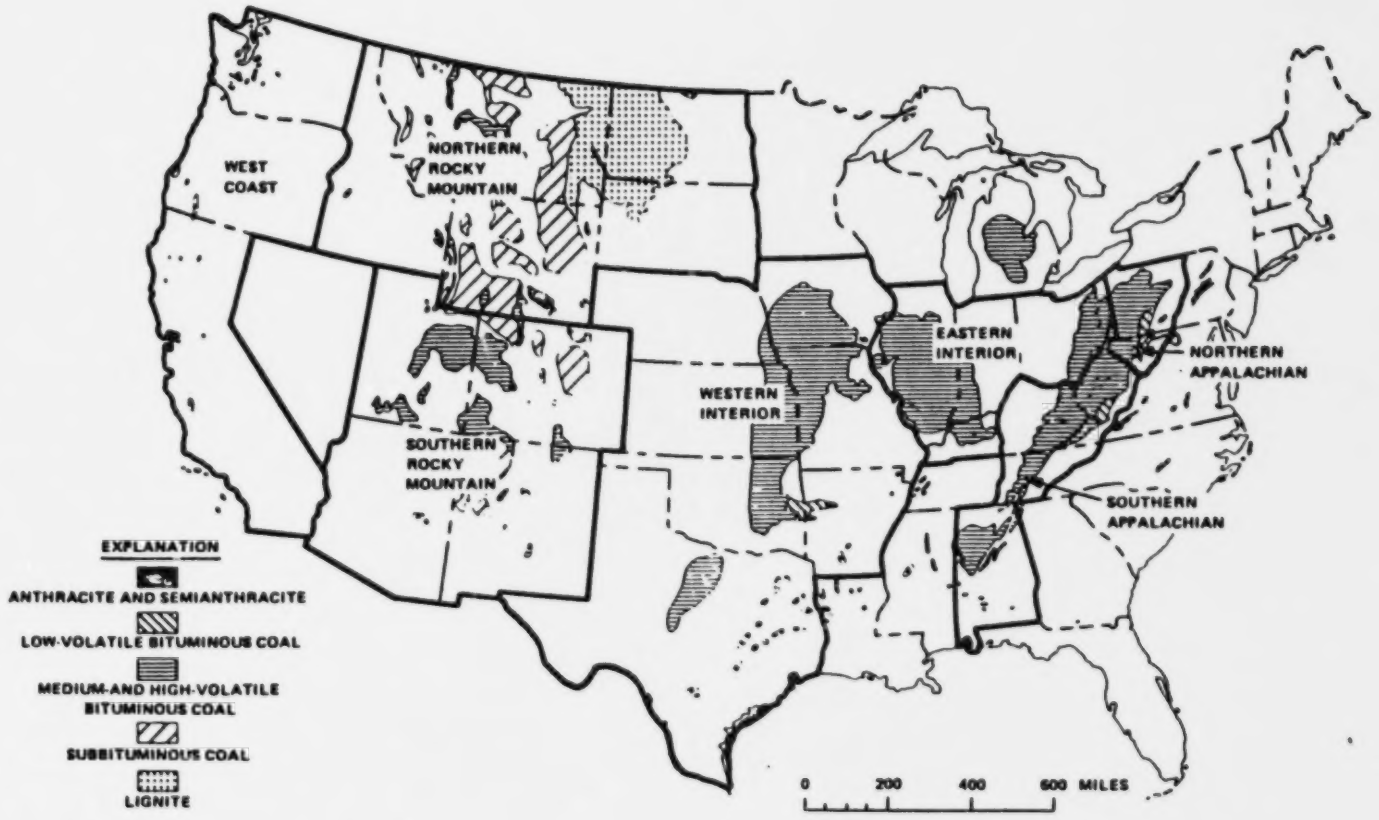
Hence, gaswells in tight formations tend to produce low flow rates over long time spans. However, technology to improve flow rates by breaking up the formations is being advanced. After two decades of experimentation, the method most commonly used today is hydraulic fracturing. This technique involves the injection of a mixture of fluids and solids into a wellhole under high pressure to create and maintain an artificial fracture. The fluid is withdrawn by pumping, and gas flows along the fracture held open by the solids. Continued experimentation and commercial experience with hydraulic fracturing should help improve gas flow rates from tight formations and the commercial viability of the operations. Estimates for the total gas in place among the 13 basins range from 50-600 Tcf, about half of which is estimated to be recoverable. The amount of gas that can be recovered is dependent on technology as well as the marketable price of such gas.

3.4 Gas From Coal Deposits (11,12,13,14)

Methane, the major component of natural gas, is generated during the natural process of coal formation. Frequently, because of the low permeability of strata associated with coalbeds, it is trapped in the coal and associated strata. The coal seam gas is primarily methane, but contains some carbon dioxide, nitrogen, and other hydrocarbons. The quality of coal-associated gas varies from essentially pure methane for predrained gas, to variable combinations of methane and air for gob gas, to an extremely diluted methane-air mixture in ventilation air. Generally for undiluted gas, its Btu value is between 950 to 1,000 Btu per ft^3 at standard conditions. The total magnitude of the U.S. coal-associated gas resource has been estimated to be between 70 and 860 trillion cubic feet. Figure 6 indicates the coalfields in the conterminous United States.

During mining operations in an underground mine, the removal of coal provides a free volume into which the methane can migrate and mix with air to form a potentially explosive or flammable mixture. The most wide-spread method of controlling methane concentrations to safe levels is dilution with ventilating air which sweeps the methane from the mine into the atmosphere.

The maximum reasonably expected gas content varies with coal rank. The American Gas Association (Reference 14) indicates values of 200 ft^3 per ton of bituminous coal, 80 ft^3 per ton of subbituminous coal, and 40 ft^3 per ton of lignite.



Source: Reference 5

Figure 6

Bituminous and Subbituminous Coal Fields of the Conterminous United States

The Federal Government and some mining companies have been investigating techniques for draining methane from coalbeds to prevent gas migration into the working area. The techniques investigated include drilling vertical or directional wells into virgin coalbeds in advance of the mine's working faces, and drilling horizontal boreholes into virgin coalbeds from a central shaft or heading. These drainage methods produce natural gas comparable to that from other gas reservoirs. Drainage from previously mined (gob) areas may be accomplished through vertical wells which provide gas diluted with air with mixtures ranging from 25 to 90 percent methane. Such techniques will significantly reduce ventilation requirements necessary to maintain concentrations at a safe level and at the same time will improve mining productivity by reducing downtime caused by hazardous levels of methane.

It has been estimated that mines in the Pittsburgh coal seam are currently venting over 100 million standard cubic feet of methane per day. The expansion of coal mining over the next 10 years, together with extensive adoption of predraining and gob draining techniques, will increase this rate considerably. At present, no commercial use is being made of this potential resource and the gas is wasted.

Coal companies are not particularly supportive of development of methane from coal as a resource. The Btu gas value per ton of coal is almost insignificant (i.e. less than 1% for bituminous coal). Another factor inhibiting methane recovery is legal, it is unclear whether a company owning coal rights also owns the methane within the coal. Although coal operators have a legal right to release methane in the course of mining, they are wary of the legal implications of gas recovery, since natural-gas rights are generally held by others. Another potential problem is quantification of mine-roof damage, if any, due to gas production enhancement via fracturing. This could severely impact on mining of affected inplace coal.

3.5 Methane From Geopressured Aquifers (8,12,15)

The Gulf Coastal Plain of Texas, Louisiana and the offshore continental shelf are underlain in many areas by sedimentary rocks with pore fluids that are confined under higher than normal pressure. These fluids are hot, and presumed to be saturated with dissolved methane at formation pressure, temperature, and salinity in addition to containing appreciable amounts of gaseous methane.

The sedimentary rocks which contain abnormally high-fluid pressures and temperatures are termed geopressured resource; the energy contained is termed geopressured energy; the part that can be extracted under present technology is termed geopressured reserve. The areas of the Gulf Coast considered most desirable for

resource exploration and exploitation generally parallel the coastline of the northern Gulf of Mexico. The approximate depth of geopressured sediments ranges from about 1500 feet to a maximum depth drilled in the Gulf Coast of 25,600 feet; with the majority of the sediments at depths greater than 4,000 feet. The vertical fluid pressure gradient ranges from 0.46 to 1.00 psi/ft in the geopressured section, and the temperature ranges from less than 100°F to 555°F. It has been estimated that the fluid contains up to 100 scf/bbl of brine, part of which (as previously indicated) is gas-phase. It is stressed that the amount of the gas in the brine is unknown.

Because of the many unknowns, quantitative estimates, as indicated, are difficult to make. This uncertainty is reflected in the current inplace-resource estimates which vary widely from a low of 3,000 Tcf to a high of 50,000 Tcf. Certainly, not enough is known to estimate how much of this resource can be economically exploited. Since the geopressured aquifers contain water under high pressure and temperature, additional energy possibly can be extracted in the form of useful heat and hydraulic energy.

In essence, the economics of natural gas production from geopressured aquifers depend on many factors, such as:

- The prevailing price of natural gas
- The cost of drilling and equipping deep wells for production
- The ability of these wells to produce large volumes (40,000 barrels per day) of water over a life time of at least 20 years
- The absence of significant environmental impact, through proper mitigation, at such production levels.

3.6 Landfill Gas (10,16)

When natural organic matter decomposes, it is transformed by the action of microorganisms abundant in the refuse into a variety of simpler organic materials. As the organic matter decomposes, byproduct gases are produced. The major components of landfill-generated gas are carbon dioxide and methane; however, lesser amounts of oxygen, nitrogen and hydrogen sulfide are frequently produced. The composition of landfill gas undergoes an evolutionary process as the refuse experiences first aerobic (oxygen-abundant), then anaerobic (oxygen-deficient) conditions. This evolution develops in four phases.

- In the first phase, lasting several days to several weeks, oxygen present at the time of refuse placement aids in the decomposition process. Carbon dioxide and water are the principal product byproducts.

- During the second phase, anaerobic conditions prevail since free oxygen has been depleted. As anaerobic decomposition begins, significant amounts of carbon dioxide as well as some nitrogen and hydrogen are produced.

- The third phase is characterized by the first evidence of methane, with a coincident reduction in the amount of carbon dioxide and hydrogen produced.

- The final phase is methanogenesis (methane production). The percentage of methane in the landfill gas may range from 50 to 70 percent with a carbon dioxide level of from 30 to 50 percent. This phase begins from six months to three years after refuse placement.

Methane production from a given refuse fill will last many years. The active gas production life is dependent on site-specific conditions. Generation life may range from only a few years to hundreds of years in certain environments. The rate of gas production is dependent upon a number of factors, including the levels of oxygen present, the refuse-moisture content, environmental pH, temperature, and refuse composition.

The typical gas-recovery system in use today employs induced exhaust wells consisting of perforated pipe casings placed in holes drilled in the refuse, backfilled with permeable material (such as gravel) and sealed with an impermeable cover material to prevent the inflow of air. Suction is applied to each well casing to withdraw the gas and transport it to a processing area by means of a pipe network. A motor/blower unit or compressor is usually the source of the applied suction, as well as the central point for collection of the gas. The gas is treated to remove particulate matter, moisture, carbon dioxide, and often trace gases from the methane. The pressure of the gas may be increased, and the temperature lowered, if required for transmission. Sales and use requirements determine the extent to which the gas is processed.

Landfill gas can be used directly (as is) or upgraded to a higher heating value. The three uses of methane-from-landfills, in decreasing order of preference, are:

- Direct use of medium-Btu gas for industrial boilers/burners, cogeneration (heat and electricity), electrical generation, on-site space heating and/or hot water heating, lighting, and recreational uses.

- Direct sale of partially processed medium-Btu gas to industrial customers.

- Upgrading of landfill gas to pipeline standard (high-Btu) gas for injection into nearby utility company pipelines.

Not all landfills produce enough gas, or gas of sufficient heating value, to be likely candidates for a major recovery project. The New York State Energy Office (Reference 10) indicates that the minimum (economic) requirements for gas recovery are:

- An inplace tonnage of 2 million tons

- A disposal rate of 150 tons per day

- An average refuse depth of 40 feet

- A surface area of 40 acres

- Two years of remaining active fill life

Table 8 lists existing landfill gas-recovery projects.

TABLE 8

Existing Landfill Gas-recovery Project

Project	Owner/Operator	Process Description[1] and Project Status
Ascon -- Wilmington, CA	Watson Energy Systems	Condensate and particulate removal; 1.5 million cfd medium-Btu gas to Shell Oil refinery for steam generation. In operation since late 1978.
Azusa Western -- Azusa, CA	Azusa Land Reclamation	Dehydration and acid removal; 500,000 cfd delivered to chemical company to generate steam. In operation since early 1978. Current plans to generate electricity for City of Azusa.
Bradley -- Sun Valley, CA	Gas Recovery Systems, Inc.	Dehydration and particulate removal; 2.5 million cfd medium-Btu gas for steam generation at Valley Steam Plant. Commercial operation since January 1981.
Cinnaminson -- Newark, NJ	Public Service Electric & Gas	Sulfur and condensate removal; 250,000 cfd medium-Btu gas to power steel plant for heating. In operation since Fall 1979.
City of Industry -- City of Industry, CA	City of Industry	Dehydration and particulate removal; 500,000 cfd medium-Btu gas for heating and cooling convention center facilities. In the start-up phase.
Monterey Park -- Monterey Park, CA	Getty Synthetic Fuels, Inc.	Dehydration and carbon dioxide removal; 4 million cfd pipeline-quality gas to Southern California Gas Company. Operational since August 1979.

[1] Including pollution control

TABLE 8 (continued)

Existing Gas Recovery Project

Mountain View -- Mountain View, CA	Pacific Gas & Electric Co.	Dehydration and carbon dioxide removal; 750,000 cfd high-Btu gas for blending into pipeline. Operated as experimental facility since 1978; currently involved in 1-year commercial project to evaluate feasibility.
Palos Verdes--Rolling Hills Estates, CA	Getty Synthetic Fuels, Inc.	Dehydration and carbon dioxide gas removal; 750,000 cfd pipeline quality gas to Southern California Gas Company. In operation since June 1975.
Sheldon-Arleta -- Los Angeles, CA	City of Los Angeles	Dehydration and particulate removal; 2.6 million cfd medium-Btu gas for steam generation at nearby plant. Commercial operation since November 1979.

Source: Reference 10

Note: It is noted that all of the landfills except one are in California. This is due in whole or in part to the fact that a given California landfill was not able to develop groundcover because of large methane formation. The correcting of this condition provided the impetus for the initiation of methane-recovery-from-landfill projects.

4.0 ENVIRONMENTAL ASPECTS OF PRODUCING GAS FROM UNCONVENTIONAL SOURCES

The considered unconventional gas resources are:

- Eastern gas shale
- Western gas sands
- Methane from coal
- Geopressured aquifers
- Methane from landfills

In general, gas obtained from the above unconventional sources are either of pipeline quality or can be upgraded to pipeline quality through the use of existing commercially available technology.

Pipeline and near-pipeline quality-gas are currently being obtained from Devonian shales and western (tight) gas sands. The well-completion techniques (e.g. explosive shooting and hydraulic fracturing) have been used for some time and environmental considerations have not inhibited well development. In addition, very small amounts of gas have been obtained from landfills and coal deposits. To date, no gas has been obtained from geopressured aquifers. Of the considered unconventional gas resources, only methane-from-coal and gas from geopressured aquifers appear to have any associated environmental concerns of significance.

4.1 Eastern Gas Shales (Devonian Shales)

Most Devonian shales must be stimulated at the completion of the well because of low flow rates. Explosive shooting and hydraulic fracturing are two means of encouraging gas flow by inducing fractures (i.e. flow paths). Gas is currently being obtained from eastern gas sands and environmental considerations have not been a limiting factor (8).

Discussions with the United States Geologic Survey (USGS) clearly indicate that environmental considerations are not expected to be a production constraining factor. The USGS indicates that well casings are emplaced under very strict standards that help insure against groundwater contamination. Selected well-stimulation methods are based in part on environmental considerations. In the past this has included the use of environmentally acceptable fracture materials (e.g. water and biodegradable foam; and water, biodegradable foam and liquid nitrogen) with withdrawal and environmentally acceptable disposal of the effluents; and explosive shooting often at depths considerably below groundwater levels.

The quality of eastern shale gas is generally very good and in many cases provides pipeline quality gas with little or no processing. Department of Energy (DOE) supplied mean off-gas compositions are provided in Table 9. The values are those after normalization to a 100 percent after subtracting the nitrogen and oxygen content to account for the samples being canned in air. The nitrogen- and oxygen-free Btu values are based on the (Table 9) indicated composition. Three of the four wells indicate attractive amounts of valuable heavier molecular components. In practice, most of these commercially valuable higher hydrocarbons would be stripped from the gas with the remainder being, or upgraded to, pipeline quality. Undesirable levels of CO_2, if present, would be removed with any of a number of commercially proven processes.

4.2 Western (Tight) Gas Sands

Two geologic characteristics of tight formations negatively impact on the recovery of natural gas from the formations. These are the low porosity and the low permeability of the formations. Technology to improve flow rates by breaking up the formation is being advanced. The method most commonly in current use is hydraulic fracturing. Fluid used for fracturing is withdrawn by pumping during the well-development phase. Fracturing techniques have been and are currently being applied to tight formations (8).

Discussions with the USGS clearly indicate that environmental considerations have not and are not expected to be a production constraining factor. The USGS indicates that well casings are emplaced under very strict standards that help insure against groundwater contamination. Selected well-stimulation investigations are based in part on environmental considerations. In the past, this has included the withdrawal of fracturing fluids, the use of biodegradable foams, and acid (HCl) fracturing which is self neutralizing when used in an alkaline base. Even so, the potential sheer number of new wells with the resultant impact from siting and constructing associated new pipeline networks to gather and transport the gas may eventually be an area of concern. However, it

TABLE 9

Mean-Off Gas Compositions From Four Shale Wells[1]

	100 Samples Well A[2]	255 Samples Well B	112 Samples Well C	19 Samples Well D
Methane	62.5%	64.6%	61.2%	88.7%
Ethane	17.1	17.7	18.5	9.6
Propane	10.4	9.8	9.5	1.1
Isobutane	0.6	0.6	0.5	0.1
Normal Butane	3.4	3.10	3.2	0.06
Isopentane	0.5	0.4	0.4	0.004
Normal Pentane	0.7	0.6	0.7	0.0
Hexanes	0.5	0.4	0.3	0.0
Benzene	0.04	0.1	0.1	0.0
Carbon Dioxide	4.4	2.9	5.7	0.5
Heating Value (Btu/scf)	1373	1371	1344	1098

[1] Values normalized to 100% after subtracting nitrogen and oxygen content

[2] Arbitrary designation

Source: Private communication from the Department of Energy's Morgantown Energy Technology Center, September 1981.

must be emphasized that unconventional gas recovery from tight sands is currently being accomplished and is similar to natural gas recovery. It is unlikely that environmental concerns will be such as to adversely impact on future overall production potentials.

Gas from what are essentially tight sands is currently being produced. Available information indicates that the quality of the gas is very good. It is anticipated that to provide gas of strict pipeline quality little if any processing will be required.

4.3 Gas From Coal Seams (8,11,12,13,17)

There are a number of factors that could impede the recovery of methane from coalbeds. These include legal aspects (e.g. ownership of gas) and the effects of gas recovery on the mineability of the inplace coal.

The hard-to-penetrate nature of most coal beds is a major impediment to producing methane at commercial flow rates from coal seams. The pockets containing gas must be tapped and steps taken to stimulate the flow of gas (e.g. hydraulic fracturing). An environmental problem is the acceptable-disposal-of-wastewaters that have collected in the gas pockets. Due to the experimental nature of coalbed gas production, figures concerning the amount of wastewater produced by the operations are lacking. However, data describing the water quality from three coalbed operations indicate that the two largest constituents are chlorides and dissolved solids with calcium and magnesium being other important components. Techniques normally used for treating wastewaters are applicable to solving this problem.

Detailed assessments of the composition of coalbed gas have been funded by DOE. The gas composition is not constant; it varies for different locations in a single coal bed. Methane is the major component, usually in excess of 80 percent. Ethane contributes up to two percent, and propane, butane and pentane constitute the balance of the hydrocarbons in the gas, with less than one percent each. Concentrations of SO_2 and N_2 vary from less than one to 15 percent; oxygen, hydrogen and helium may be present in trace quantities. Carbon monoxide and sulfur compounds are usually absent. The calorific value of the gas is a direct function of the total hydrocarbon content. Generally, the heat of combustion varies between 950 to 1,000 Btu/cu. ft., and is similar to the heat of combustion of natural gas. Table 10 indicates the composition of Appalachian coalbed gas as provided by DOE. Table 11 indicates the composition of gob gas as provided by DOE. As might be expected the characteristics of gob gas are difficult to predict. The gas quality depends largely on how much ventilating air has become mixed with the gas before it is drained from the mine. The rate at which methane will drain into the gob areas depends on very

TABLE 10

Composition of Gas (Percent Volume) From Virgin Coal by Coal Source

	Va.	Va.	Va.	Pa.	W. Va.	Pa.	Colo.	Okla.	Ala.
CH_4	97.07	63.1	97.61	95.86	84.4	99.17	87.84	99.22	96.05
C_2H_2	1.25	0.85	1.32	1.08	--	0.02	0.05	0.01	0.01
C_3H_8	0.0011	--	0.0027	--	--	--	0.0046	--	--
C_4H_{10}	0.0001	--	0.0013	--	--	--	0.0011	--	--
C_5H_{12}	--	--	--	--	--	--	--	--	--
CO_2	0.20	0.06	0.30	2.54	14.75	0.18	11.99	0.06	0.1
O_2	0.16	--	0.04	0.06	0.2	--	--	0.1	0.05
N_2	2.79	35.96	0.70	0.46	0.65	0.64	0.09	0.6	3.5
H_2	0.02	0.005	--	--	--	--	--	--	Trace
H_e	0.05	0.03	0.02	--	--	--	--	--	0.27
Btu/ft³ (as mined)	1,058	689	1,066	1,043	900	1,059	938	1,058	1,024
Btu/ft³ (CO_2 free)	1,061	689	1,069	1,046	1,015	1,060	1,066	1,059	1,026

Source: Reference 12

TABLE 11

Composition of GOB Coal Gas (Percent Volume) From Pittsburgh Coalbed Mines

	No. 1[1]	No. 2	No. 3	No. 4	No. 5	No. 6	No. 7	No. 8	No. 9	No. 10
H_2	--	--	--	--	--	--	--	--	--	--
O_2	3.42	0.37	0.09	2.93	0.29	0.65	0.63	3.15	3.25	2.35
N_2	38.45	1.68	0.71	55.32	2.00	21.57	20.29	38.40	14.51	11.49
CO	--	--	--	--	--	--	--	--	--	--
CH_4	56.22	96.73	98.05	37.31	97.47	70.70	72.07	56.83	73.08	77.50
C_2H_6	0.02	0.07	0.08	0.25	0.13	0.64	0.77	0.02	0.07	0.08
CO_2	1.91	1.14	1.05	4.10	0.10	6.34	6.16	1.60	8.26	8.58
C_2H_4	--	--	--	--	--	--	--	--	--	--
C_3H_8	trace	0.01	0.02	0.07	0.01	0.67	0.07	trace	trace	trace
$C_4H_{10}(i)$	trace	trace	trace	0.01	trace	0.02	0.01	trace	trace	trace
C_4H_{10}	trace	trace	trace	0.01	trace	0.01	0.01	trace	trace	trace
H_2S	1ppm	1ppm	trace	0	0	1ppm	1ppm	0	1ppm	0
CH_3SH	0	0	0	0	0.1ppm	0.5ppm	0	0	0	0
Heating Value[2]	569	980	994	384	989	747	745	575	740	786

[1] arbitrary sample designation,

[2] Btu/scf as-based on reported chemical constituents

Source: Reference 17

site specific conditions. Studies sponsored by DOE found that the methane content of gob gas is often in excess of 70 percent. In fact 35 percent of the samples analyzed contained in excess of 93 percent methane.

4.4 Gas from Geopressured Aquifers (8,12,15)

The environmental impacts are, generally, three fold: thermal and mineral pollution, and subsidence. One estimate is that five trillion barrels of brines would ultimately be produced from geopressurized aquifers. This is the equivalent of the total flow of the Mississippi River over a two-year period. The brines are known to be saline, extremely hot, and contain boron which in minute amounts is toxic to marine life. Reinjection of these waters to shallow aquifers; or channeling them to open seas are two considered solutions to brine disposal.

The fluids present in geopressured reservoirs vary widely in water-quality characteristics as based on well-sampling programs. Past programs indicate that the level of total dissolved solids cover a range from 22,000 to 274,000 mg/1. Toxic elements including trace metals may be present.

Economic utilization of the resource dictates the extraction of large volumes of fluids. The extraction of these fluids will cause a reduction in reservoir pressure, and an increase in effective stress in the reservoir framework. In those areas of the Gulf Coastal Plain where groundwater extracted from shallow aquifers has caused stress changes, surface subsidence often resulted. Consequently, the major environmental concerns associated with the development of geopressured resources relate to the possibility of subsidence of land surface in the immediate vicinity of the producing wells, and the disposal of the large volume of produced brine. Even though there is a smathering of information on geopressured aquifers it must be appreciated that substantial amounts of additional information are required before a determination can be made as to the number of economic reservoirs and the associated gas recovery characteristics.

Little data are available in the public domain on specific physical and chemical characteristics of the contained waters, such as temperature, pressure and dissolved contaminants. Additionally, the methane saturation of these waters as a function of temperature, pressure and water salinity is not defined. The technology must be developed to economically produce the waters at the required flow rates and to extract the methane efficiently. Large volume geopressured water production may result in land subsidence and increased tectonic activity along growth faults. The technical and environmental aspects of disposal of large quantities of brine contain many unknowns. Another unknown is the chemical composition

of the gas. A study prepared for the Gas Research Institute (Reference 15) indicates that the expected gaseous components are methane, carbon dioxide, oxygen, water vapor and traces of hydrogen sulfide.

Subsidence from withdrawal of huge quantities of water is a potential concern. Earthquakes are a considered possibility, even though existing data are absent and currently not being collected. This may restrict the reservoirs that could be tapped as well as the sequence of reservoir selection.

4.5 Landfill Gas (10,16)

Until recently, little was known of the danger of landfill-generated methane gas; explosions causing injuries and death, as well as extensive property damage, were often erroneously attributed to other causes. In 1969, however, methane gas from a nearby landfill was identified as the cause of an explosive flash fire which left 25 men dead or injured at the National Guard Armory in Winston Salem, North Carolina.

Landfill gas is typically comprised of about 50% methane and 50% carbon dioxide, although the percentage by volume of both the methane and the carbon dioxide can vary widely. Nitrogen and oxygen are normally present in small amounts as a result of air being trapped as the waste is deposited or as a result of a negative internal pressure when landfill gas is extracted. In addition, there are trace amounts of numerous compounds present in the landfill gas. Typical landfill gas composition and characteristics are shown in Table 12.

If raw landfill gas is to be used for space heating or hot water heating, the only processing required is simple water and particulate removal. There is no need for an elaborate and expensive control technology. Furthermore, since such uses do not require large volumes of gas, they are suited to the many smaller landfills across the country. Landfill gas upgraded to pipeline quality-gas (upgraded to close to 1,000 Btu) can be used for any application to which natural gas is usually put. Consequently, most large landfills pursue this application of landfill gas. In addition to moisture and particulate removal, this processing would include CO_2 removal. The process technology necessary to achieve this quality gas is relatively straightforward, off-the-shelf technology, but large capital expenditures are involved.

Since a landfill gas-gathering system helps mitigate malodors, gas hazard, and vegetative stress, a recovery system has a generally favorable environmental impact overall. Negative impacts on air quality, water quality, noise levels and traffic should be minimal.

TABLE 12

Typical Landfill Gas Composition and Characteristics

Component	Component percent (dry volume basis)
Methane	47.5
Carbon dioxide	47.0
Nitrogen	3.7
Oxygen	0.8
Paraffin hydrocarbons	0.1
Aromatic & cyclic hydrocarbons	0.2
Hydrogen	0.1
Hydrogen sulfide	0.01
Carbon monoxide	0.1
Trace compounds[1]	0.5

Characteristic	Value
Temperature (at source)	106°F
High heating value (hhv)[2]	476 Btu/scf
Specific gravity	1.04
Moisture content	Saturated (trace compounds in moisture)[3]

[1] Trace compounds include sulfur dioxide, benzene, toluene, methylene chloride, perchlorethylene, and carbonyl sulfide in concentrations up to 50 ppm.

[2] Landfill gas (as received) from Palos Verdes landfill has a hhv of 581 to 586 Btu/scf (Bowerman 1977). Landfill gas (as received) from a Mountain View landfill test well has a hhv of 441 to 451 Btu/scf with a 20-21 percent nitrogen content by volume (Blanchet 1977, Carlson 1977).

[3] Trace compounds include organic acids 7.06×10^{-3} ppm and ammonia 7.1×10^{-4} ppm.

Source: Reference 16

Flare emissions can contain particulates as well as SO_2, HNO_3, HCl, and CO--all regulated pollutants. Most gas-recovery systems will require at least minimal processing of the recovered gas, including removal of moisture. The resulting moisture condensate, which is very corrosive, will have to be neutralized before it can be disposed (e.g. discharged into the sewer system).

5.0 AVAILABLE TECHNOLOGY FOR PROCESSING UNCONVENTIONAL GAS

In general, the degree of upgrading and/or cleanup required for gases from the considered unconventional sources are as follows:

Gas Source	Gas Cleanup Required
Western Gas Sands	None to minimal
Devonian Shale	None to minimal
Coal Seams	None to moderate
Geopressured Aquifers	Possibly moderate or greater
Landfills	Minimal to moderate (depending on utilization)

There exist a mature technology base and a number of developed and available processes for upgrading and removing undesirable components (e.g., H_2O, CO_2, H_2S, carbonyl sulfide (COS)) from gases. The removed sulfur compounds may be converted to marketable elemental sulfur or sulfuric acid or may be disposed of in accordance with environmental regulations. In this regard, there exists a significant number of proprietary and non-proprietary processes that have been used in the past and are currently being used.

As an example, CO_2 can be removed from a combustion gas by absorption into a liquid, adsorption on a solid, membrane separation, cryogenic separation, or chemical conversion into another compound. Moisture can be removed by dehydration and H_2S by any of a number of adsorption related processes. Particulates can be removed by the use of centrifuges, membranes, packed beds, and liquid scrubbing.

Control-technology processes that have or are currently being used to upgrade natural gas include (18):

Process	Can be Used for Removing
Alkazid	H_2S, CO_2
Hot Carbonate (Benfield)	H_2S, CO_2
Purisol	H_2S, CO_2, acidic components
Selexol Solvent	H_2S, CO_2, COS, mercaptan
Sulfiban	H_2S, COS, CS_2, HCN, some CO_2
Sulfinol	H_2S, CO_2, COS, mercaptans
Activated Carbon Adsorption	H_2S, COS, mercaptans
Molecular Sieve	H_2S, COS, mercaptans, and some other impurities

In essence, the chemical industry currently has a mature technology base that includes many proprietary processes that can be used to clean and upgrade gases from the considered unconventional sources to pipeline or industrial-user quality.

In the interest of pursuing energy independence and a cleaner environment, the resource base of these unconventional sources of natural gas should be more clearly determined and associated recovery techniques improved. A more comprehensive study of environmental concerns should be made at that time. Until that time it is hoped that this overview will be helpful to those policy makers concerned with minimizing the environmental inpacts of total energy production.

APPENDIX

Pipeline Quality Gas

In order to inject methane gas directly into commercial pipelines, the gas must meet certain specifications established by the pipeline gas companies. Specifications on quality of purchased gas set by the Equitable Gas Company are listed below (obtained from Reference 12). The barometric pressure for pressure calculations is 14.73 psia.

The gas quality shall:

a. Be in its natural state as produced

b. Be commercially free from dusts, gums, gum-forming constituents, or other liquid or solid matter which might become separated from the gas in the course of transportation through pipelines

c. Not contain more than three-tenths (0.3) of a grain of hydrogen sulfide (H_2S) per one hundred (100) cubic feet

d. Not contain more than thirty (30) grains of total sulfur per one hundred (100) cubic feet

e. Not contain more than four percent (4%) by volume of a combined total of inerts such as carbon dioxide, nitrogen, argon and helium; provided, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume

f. Not contain more than one percent (1%) of oxygen by volume

g. Have at least nine hundred and fifty (950) British Thermal Units per cubic foot calculated as the gross saturated value at 14.73 psia and 60°F

h. Be dehydrated by seller, if necessary, and shall in no event have a water content in excess of seven (7) pounds of water per million cubic feet of gas measured at the purchase base of 14.73 psia and 60°F

i. Be in conformance with any existing regulatory standards.

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